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Onshore and Offshore EOR Applications in Brazil: A Review Study

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Abstract

This study reviews the existing oil and gas fields in Brazil located both onshore and offshore. Focus is on geology and production history of Santos, Campos, Reconcavo, Sergipe, and Potiguar Basins. We mainly reviewed the geological and reservoir characteristics of these basins, their production history, applied enhanced oil recovery (EOR) methods, and we finally made some EOR recommendations which may help to increase hydrocarbon recoveries in each basin.

At the beginning of the current decade, Brazil was producing almost 2 MM barrels of oil per day. Nowadays, the pre-salt fields alone (that started operating 15 years ago) produce an average of 1.67 MM bbl/d with a 2.73 MM bbl/d total daily oil production. In other words, the oil production from the basins other than the pre-salt fields started to decline of more than 50% in their production levels.

The divestment of many assets, located both onshore and offshore, opens a window of opportunity and a need for the new owners to apply EOR methods to bring back production to higher levels and recover their investments. By reviewing the data from three onshore fields from Reconcavo, Sergipe, and Potiguar and two offshore fields from the Campos basin, this paper has discussed issues and assessed alternatives that may similarly be applicable to other fields in the same basins. Buracica, Carmopolis, and Canto do Amaro fields presented almost none to low increase in production. One of the reasons may be credited to paraffin wax deposition. To avoid wax deposition and increase oil production, we proposed to combine two methods; a thermochemical method to avoid the buildup of wax with the addition of surfactant to the injected fluid to reduce the interfacial tension between water and oil and increase recovery. Both Jubarte and Marlim have achieved success with waterflooding but currently, a continuous decline is observed. Polymer flooding is proposed as a solution in these cases. The pre-salt fields are still ramping up production at very high rates. Hence, as an alternative, in those reservoirs, CO_2-WAG might be applied in the near future before reaching a decline in the oil production.

This study briefly discusses the status of the oil and gas fields in Brazil both located onshore and offshore. Moreover, it provides quick recommendations for the existing problems in Brazil during oil and gas production via EOR methods.

Introduction

Brazil is currently attracting interest from many international oil companies after the discovery of several giant offshore fields in the last decade. These fields more than doubled the country 1P (proved) reserves at the end of 2018 to 13.8 B bbl (billion barrels of oil) and 368.5 B cubic meters of natural gas (ANP, 2019). Hence, Brazilian Exploration and Production (E&P) industry is heavily tilted offshore, becuase 96.1% of the oil and 96.9% of gas reserves are located below the seabed.

Nonetheless, many other onshore and offshore mature fields that have been producing for decades, still contribute to one third of the country's total oil & gas output. Some of them are still using an artificial lift process, such as rod pumps at onshore fields in the northeast region basins (Recôncavo, Tucano Sul, Alagoas, Sergipe and Potiguar) or electric submersible pumps at offshore fields at Campos basin. Some of these fields are also being waterflooded. Tertiary recovery methods are not widely applied and are being limited to only a few onshore fields. Such a fact offers opportunities for current operators and companies acquiring mature fields to apply Enhanced Oil Recovery (EOR) methods and increase oil production.

Exploration and production evolution in main basins

Figure 1 identifies the main sedimentary basins in Brazil on the map of the country.

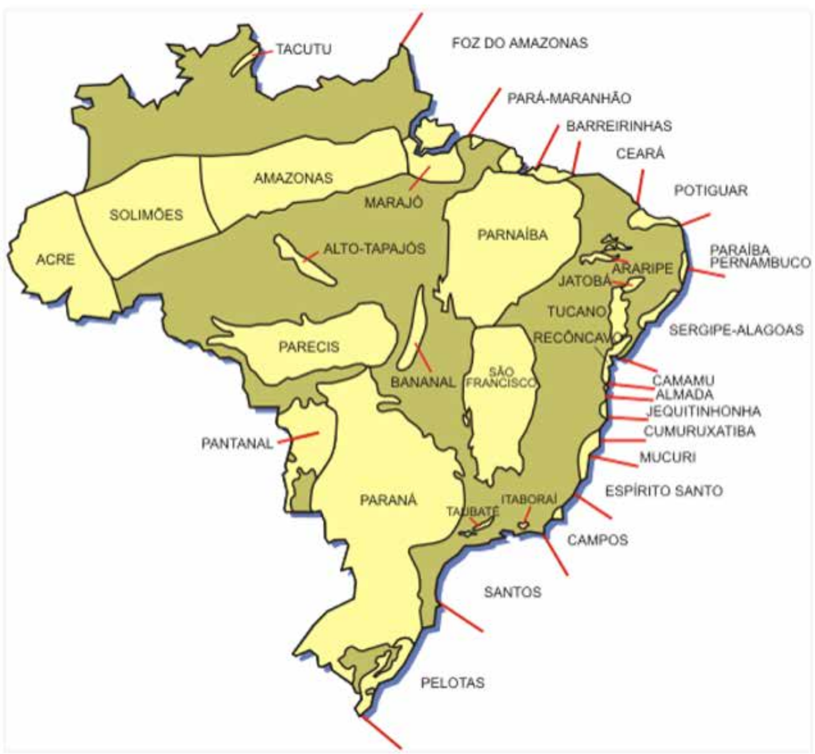

Figure 1—The main sedimentary basins in Brazil (ANP, 2019)

After many unsuccessful drillings across the country since the late nineteenth century, commercial petroleum production began in 1941 at Candeias field, Recôncavo basin.

The development of the oil industry in Brazil is intertwined with the history of the national oil company Petroleo Brasileiro S.A. - Petrobras. Petrobras was founded in 1953 as an outcome of a nationalist campaign that established the monopoly of the company in all activities related to exploration, production and refining of oil and gas.

Two decades later, in 1961, a second basin started to produce oil & gas: Alagoas. It was followed by the Sergipe basin - Carmópolis field, the largest onshore field to date - and Potiguar basins in 1963. The development in the first decades was limited by the restricted capital available for investment and the low productivity from these basins. By 1960 Petrobras was producing 80,000 boe/d (daily production in barrels of oil equivalent (liquid oil + natural gas)). Ten years later, in 1970, the daily average had increased by 100,000 boe/d to a total of 180,000 boe/d.

The discovery of the first offshore field located in the shallow waters of Campos Basin created solutions for the country's hydrocarbon need. Production from the Enchova field started in 1977. In the 1980's, after advancing into deeper (and later into ultra-deep) waters, Petrobras made its first sizeable field discovery in Brazil: Albacora, with 4.8 MM barrels of oil originally in place (OOIP). This was followed by a sequence of other fields with more than 1 billion barrels of oil (bbl) in place in the following two decades. Among them are Marlim, Marlim Sul, Marlim Leste, Roncador, Barracuda, Caratinga e Jubarte which added up to 67.7 B bbl OOIP. As a result, the total Petrobras daily production, which averaged around 220,000 boe/d in 1980, increased threefold (740,000 boe/d) ten years later.

Santos Basin, which neighbors the Campos Basin to the South, had its first commercial production in 1991: Merluza (the first non-associated offshore gas field). The country's daily production doubled in a decade achieving 1.5 MM boe/d in the year 2000 and continued increasing to 2.6 MM boe/d in 2010. The cumulative production of oil in barrels per basin can be seen in Figure 2.

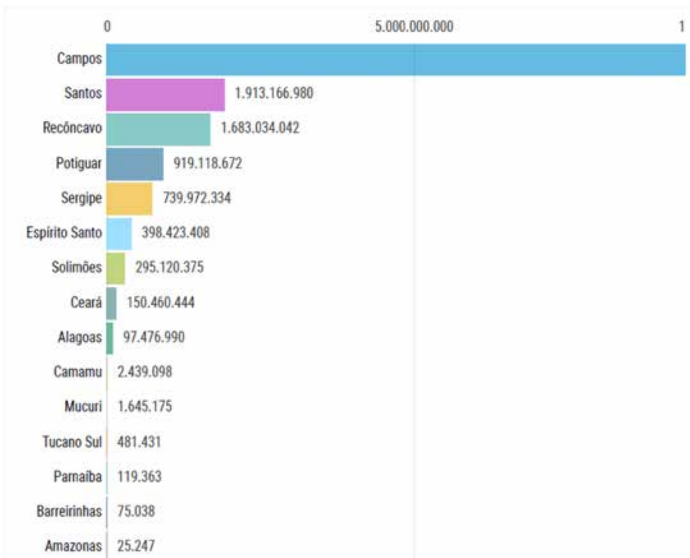

Figure 2—Brazil's Cumulative Oil Production per basin (in bbl). (ANP, 2019)

In 1997 a new legislation was approved. In this new legislation, private companies were allowed to become partners of Petrobras in blocks under exploration and in producing fields. Two years later the first bid round took place when concession areas were awarded to private companies to operate them. The pre-salt reservoirs, the carbonate reservoirs below a thick layer of salt, since 2006 are the hot bed of oil & gas exploration and production in Brazil. Thirteen years after the first exploration well drilled in Lula field (Santos Basin), the pre-salt reservoirs (spreading also under Campos basin) are responsible for 2.1 MM boe/d – almost two thirds of total hydrocarbon production in Brazil. Oil and gas production achieved an average of 3.473 MM boe/d across all Brazilian basins in May 2019. Currently, offshore fields are responsible for 93.6% of total hydrocarbon production in the country, with fields in Santos and Campos Basin being the main contributors with 57.4% and 34.2% each, respectively.

The development of the Campos basin first (since the late 1970's) and the Santos basin (in the 2010's) later demanded most of the resources from Petrobras, understandably, given the larger reserves in place offshore. Therefore, the onshore fields fell out of preference in terms of investment. Nevertheless, Petrobras maintained its existing onshore concessions while developing the offshore reservoirs. Hence, the company still owns 74.5% of total oil production as concession holder and is responsible, as operator, for 93.3% of oil production.

Then, Petrobras changed strategy and started a divestment program of mature fields both onshore and offshore. Thirty-four fields from Potiguar Basin have been sold in 2019 and other thirty-two fields across Recôncavo and Sergipe basins are up for sale. Lower EUR (Estimated Ultimate Recovery) offshore fields at the Campos basin have also been sold; Pargo/Vermelho, Carapeba, Enchova/Pampo and Bauna. These are mainly oil production fields whose production averaged around 50,000 - 100,000 bbl/d but declined to 5,000 - 20,000 bbl/d range and that have undergone neither secondary, nor tertiary recovery. Only the larger fields (i.e.: Marlim) received investment to adapt their platforms and drill injector wells to waterflooding.

Given the brief historical background described above, this review will focus on the recovery characteristics of specific onshore and offshore fields. Onshore, one field from each of the main basins, Recôncavo, Sergipe and Potiguar, was chosen: Buracica, Carmópolis and Canto do Amaro. The intention is to propose alternatives that can be employed in other fields in the same basins. Offshore, two mature fields (currently being flooded with water) were chosen: Marlim and Jubarte in the Campos Basin. Such analysis may be of interest for the new owners of the fields recently sold in the same basin. The scope of this review also includes two highly prolific pre-salt fields in the Santos basin: Lula and Mero and the ongoing CO_2 injections.

Onshore: mature and underinvested fields

Recôncavo, Sergipe, and Potiguar basins stride through land and sea. This section lays emphasis on the onshore part of these basins which is most relevant in terms of production. The main hydrocarbon reservoirs at both Recôncavo and Potiguar basins are composed of deltaic, fluvial-deltaic, fluvial-aeolian, and turbidites sandstones. The Sergipe basin has a diversity of rocks as hydrocarbon reservoirs. These include sandstone reservoirs (fluvial, deltaic, fluvial-deltaic) in its majority and some turbidites, conglomerates, and carbonates.

Buracica, Carmópolis, and Canto do Amaro were chosen to be reviewed in details due to their long producing life (since 1959, 1963, and 1986, respectively). Similar reservoir formation (sandstones) can be observed, and some similar techniques were applied: artificial lift, secondary, and tertiary methods.

Reservoir Rock and Fluid Properties for Buracica, Canto do Amaro, and Carmópolis Fields and the Summary of the Applied Recovery Methods. The reservoir rock and fluid properties are listed in Table 1 for these three reservoirs.

Table 1—Reservoir Rock and Fluid Properties of Carmópolis, Buracica, and Canto do Amaro (M.A. de Melo et al., 2005)

PARAMETER	SCREENING	CARMÓPOLIS	BURACICA		CANTO AMARO
Temperature (ºF)	*< 176*	122	140		131
Salinity (ppm)	*< 50,000*	30,000	33,000		500
Oil viscosity (cP)	*< 100*	50	10.5		20
API	*> 15*	20-29	34		28-45
Oil saturation (%)	*> 20*	> 50	> 50		> 50
Permeability (mD)	*> 100*	100	150 - 900	850 - 1,450	146 - 1,994
Porosity (%)	-	15 - 30	21.9 - 25.2	21.0 - 27.0	9.5 - 29.6
Mobility ratio	*> 1*	12	3		2
Heterogeneity	*low*	high	high		low
Clay content (%)	*low*	high	high		low
Depth (ft)	-	2,297	1,050	2,120	476 - 3,281

Previously, Canto do Amaro and Carmópolis have been waterflooded for enough time to see a second production decline. An immiscible CO_2 injection started in Buracica in 1991, but its results were short-lived. Polymer flooding was chosen, then as the tertiary method of preference and a pilot test was developed.

To help with the determination if polymer flooding would be a good candidate in these three reservoirs, the Table 1 also lists the screening criteria for polymer flooding (Chang, H. L. 1978; Al Atwah et al., 2018). Polymer flooding is preferred in reservoirs with unfavorable mobility ratios (M>1.0).

The most critical reservoir fluids and rocks characteristics for polymer flooding are the reservoir temperature, reservoir salinity, and the oil saturation. The mobility ratio also played a huge part in the decision of choosing polymer flooding. The injected polymer causes the viscosity of water to increase, thus, the mobility ratio will decrease which will help to displace more oil. Because the high clay content can increase the adsorption of the polymer in the rock, clay type and amount and its interaction with the injected polymer should be checked prior to application. High heterogeneity has also been a problem for all EOR methods, but polymer flooding improves the sweep efficiency (M.A. de Melo et al., 2005; Gao, C. 2013; Bealessio et al., 2021).

Polymer flooding results. Polymer flooding has been a very popular method of enhanced oil recovery method for decades. It is widely used to control the mobility of the injected water in EOR applications for oil reservoirs that have an unfavorable mobility ratio (M>1) (Yongkyeong Lee et al., 2018).

In the case of Carmópolis, Buracica and Canto do Amaro fields, polymer flooding was used as the first enhanced oil recovery method after a huge reduction in oil production was observed. the injected water viscosity was increased by the addition of polymer; hence, oil recovery factor is increased with the increase in the vertical and areal sweep efficiencies. On the other hand, the reservoir permeability was decreased in some areas. Also, blockage of the high permeable channels with injected polymer was enhanced the oil recovery (Islam R., 2015).

Both synthetic polymers and biopolymer were tested in the laboratory for all three fields. All laboratory tests were done with a shear rate of 7.3 which is representative of the reservoir flow conditions (Arezoo Rezaei et al., 2016). Due to reservoir flow conditions and low flow viscosity, partially hydrolyzed polyacrylamide (HPAM), a non-Newtonian fluid with a pseudoplastic rheology, was selected for all three fields.

After the injection of polymers into the candidate reservoirs of Carmópolis, Buracica and Canto do Amaro, the results were unexpected (different than what was obtained in the laboratory) due to the high-level water saturation and possible degradation of the polymer due to the water salinity. The Buracica field has only increased in oil production by 2.8% after polymer flooding. The Carmópolis field did not have an increase in oil production until after almost three years of the polymer injection, and the reservoir reacted to the polymer with a pressure increase. However, the polymer flooding helped the reservoir to block the high permeable flow channels. The Canto do Amaro field had an increase in oil production approximately one year after injection. The reservoir pressure increased proportionally to the viscosity of the fluid injected. The high flow permeable channels were blocked by the polymer on this reservoir, as well (M.A. de Melo et al., 2005).

Figure 3 shows the production history of Carmópolis field since it started operating in 1963. Within the chart, there are three easily distinguishable phases. The first phase is from start-up until circa 1979, when waterflooding started in a large scale (it had already been implemented at the central part of the field in 1971 as per Mezzomo et al., 2001). Polymer flooding began during the second phase, which lasted until 1997, and continued with the same method during the third phase. The delay in the results of polymer flooding can be identified in the graph which can be seen in 2002 when a significant production increase is observed. The rate continues increasing until peaking above 25,000 bbl/d in 2014. Since then, it has been declining, achieving an average of 6,750 bbl/d in the five initial months of 2019. This strongly indicates that polymer flooding alone has achieved its maximum efficiency. With a cumulative oil production of 381 MM bbl in

2015 (ANP, 2015), a little more than 22% of OOIP has been recovered. Alternative EOR methods must be assessed and implemented if Carmópolis is to fulfill its potential.

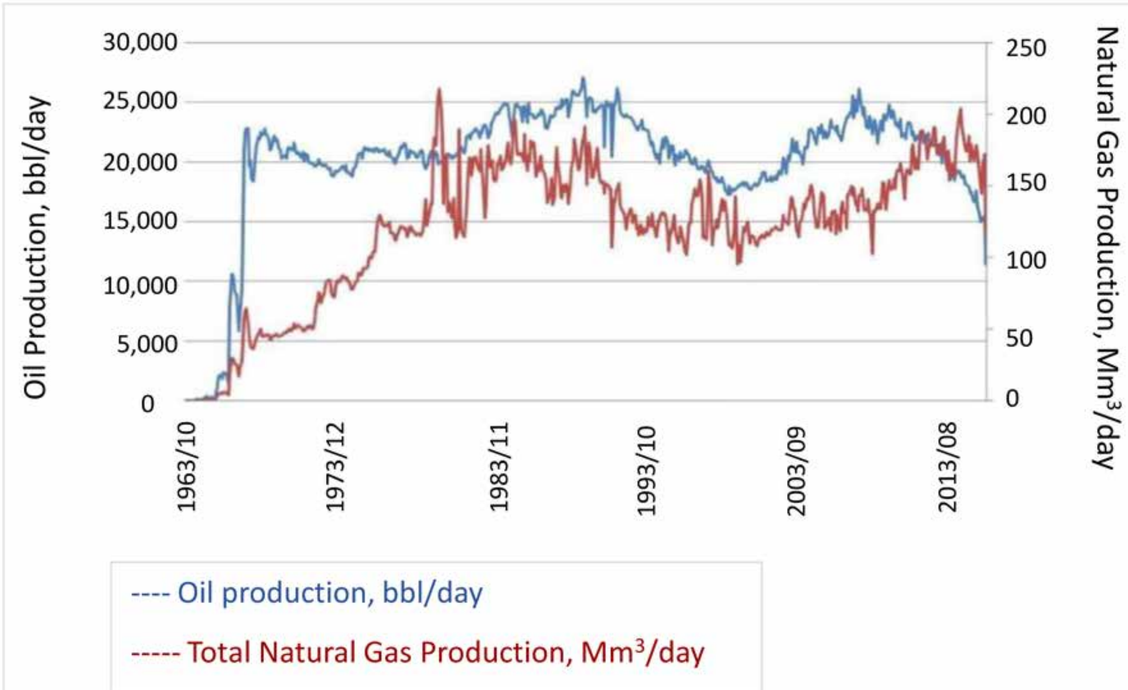

Figure 3—Historical Production - Carmópolis Field (ANP, 2016)

Figure 4 represents the Buracica field production history and the impact of the polymer injection started in 1997. The production increased very slightly for almost 10 years but then started to decrease. By December of 2015, the field had cumulatively produced around 30% of its OOIP (ANP, 2016). The production could be increased by applying another EOR method in the future.

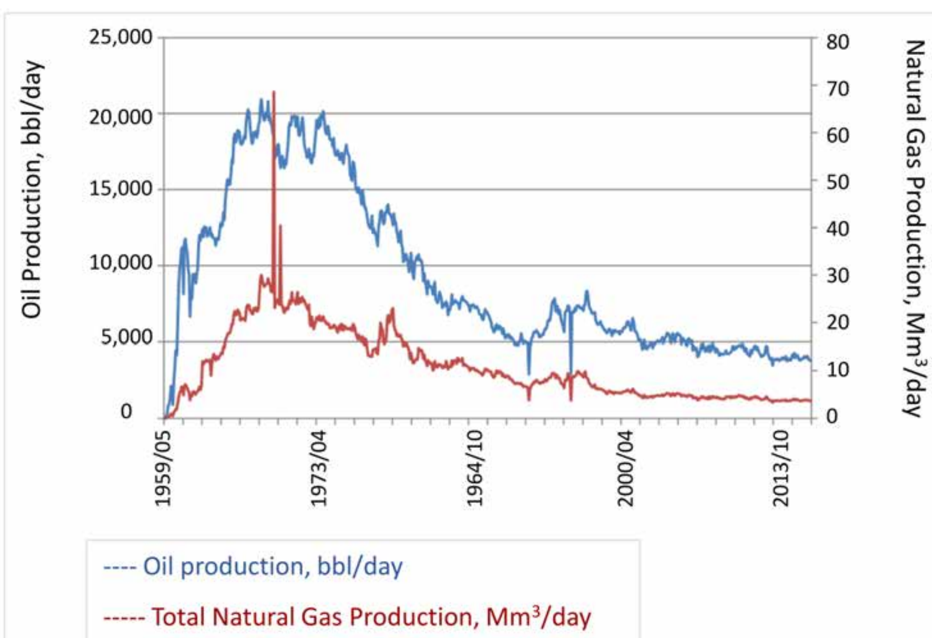

Figure 4—Historical Production - Buracica Field (ANP, 2016)

Canto do Amaro also has three significant phases, as indicated in Figure 5. It is shown that the primary oil recovery was until 1996, the second recovery method using waterflooding was until 2002 and the polymer flooding that was applied resulted in a rocket increase in production during 2003 to 2006. The production of oil was around 278 MM bbl whereas the OOIP was 1.3 B bbl by December of 2017 (ANP, 2018), configuring a good reason for an alternative EOR method.

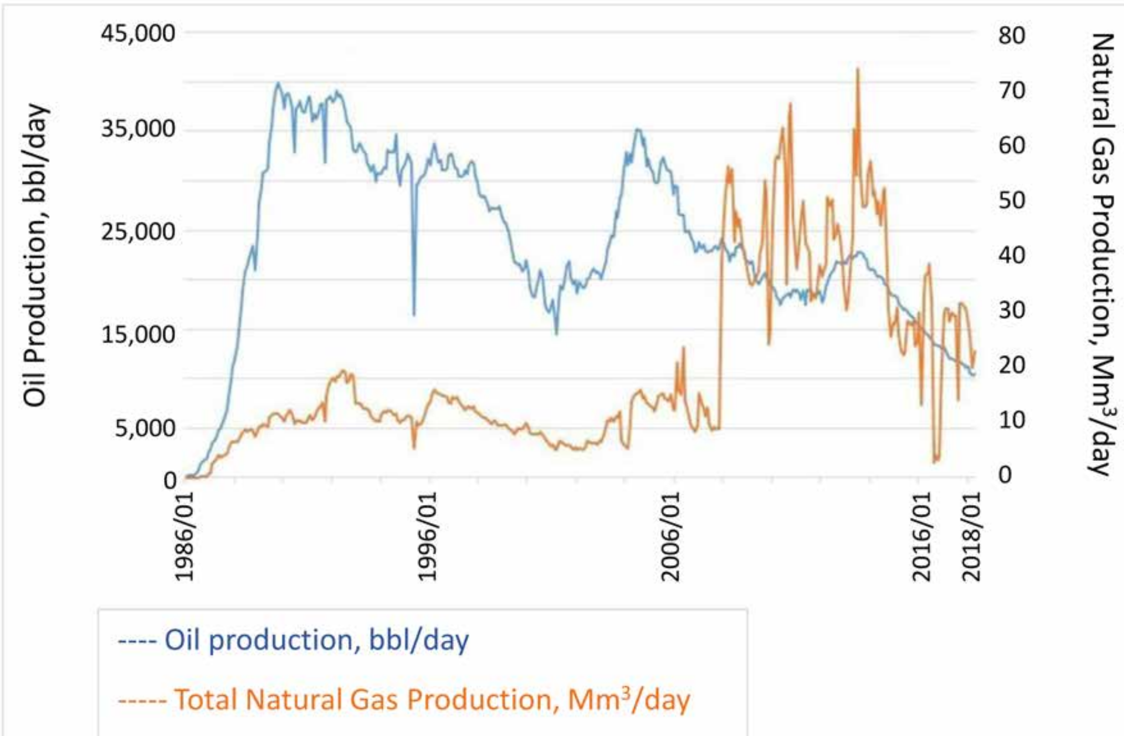

Figure 5—Historical Production - Canto do Amaro Field (ANP, 2018)

Alternate enhanced oil recovery methods that can be applied on onshore basins.

Thermochemical process

Recôncavo and Sergipe Basins have a recognizably lower rate of production compared to the main offshore basins (Campos and Santos). One of the reasons for the lower production rates in the onshore basins is due to the significant amount of paraffin wax content (Silva et al, 2004). Paraffin wax is a long straight chain hydrocarbon (more than 15 atoms of carbon) with a wide range mixture of a nonpolar high molecular weight of alkanes, which can coagulate and precipitate under a certain change in a pressure and temperature (Speight, 2010). To solve the paraffin wax problem occurring in these basins there must be an application of an unconventional technique. The suggested method, developed by *Centro de Pesquisas Leopoldo Américo Miguez de Mello* also known as CENPES (Petrobras research center), highlights the use of a thermochemical technique by applying a strong exothermic chemical reaction. The chemical reaction occurs in the aqueous emulsions between two nitrogen salts by using an organic solvent as shown in the reaction formula below. The exothermic chemical reaction results in a significant amount of nitrogen formation and heat release.

$$NaNO_2 + NH_4Cl \rightarrow N_2 + NaCl + 2\ H_2O + \Delta H \qquad \text{Eq.1}$$

$$2\ NaNO_2 + (NH_4)_2\ SO_4 \rightarrow 2\ N_2 + Na_2SO_4 + 4\ H_2O + \Delta H \qquad \text{Eq.2}$$

The amount of heat resulting from the reaction helps liquified the paraffin wax. Moreover, the nitrogen resulted from the reaction makes a ternary process between the nitrogen/water/solvent causing efficient fluidization of the paraffin wax content (Rocha et al, 2003). The process of the chemical reaction and its effect on the phase of the paraffin wax is shown in Figure 6. Diesel was used as the solvent in this reaction due to its similar properties such as kinematic viscosity (Bennett, 2014). Some other solvents were also provided promising results (Kar and Hascakir 2021b).

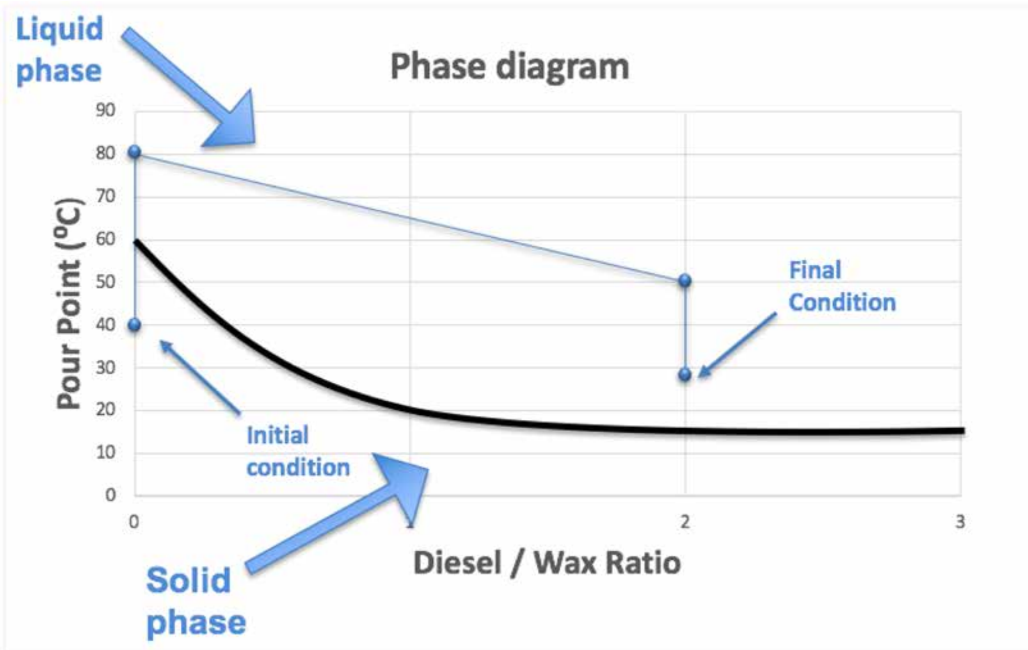

Figure 6—Phase diagram of the paraffin wax with the exothermic chemical reaction

Looking at Figure 6 again, it is noticed that the phase change of the paraffin wax from a solid phase to a liquid phase is done by the process of an exothermic chemical reaction. Initially the hydrocarbon starts with a solid phase (paraffin wax) at pour point of 40ºC, then moves to its final condition in a liquid phase at pour point of 37ºC. The pour point is the lowest temperature where the hydrocarbon would be mobile, so lower pour point results in less wax content (Speight, 2015).

The experiment results are shown in Table 2 for the oil samples before and after applying the thermochemical technique. The table displays a change in the physical and chemical properties of the samples. For example, the pour point, wax content, and the apparent viscosity decreases, and the wax appearance temperature increases. All these results positively affect the process of removing the paraffin wax and essentially increase the oil recovery.

Table 2—Experiment results of applying the thermochemical process

PARAMETERS	BEFORE	AFTER
Pour point (°C)	42	37
Wax content (%)	27	24
Wax Appearance Temperature (°C)	40	43
Apparent Viscosity at 100/S (cP)	85	30

Surfactant flooding. Another EOR method that is suggested for the onshore basins is surfactant flooding. Surfactant flooding is a tertiary method used to increase the capillary number to extract more oil. Increases in the capillary number leads to a decrease in the residual saturations; however, the capillary number depends on many factors, one of which is the interfacial tension. Reduction in the interfacial tension will increase the capillary number. Applying surfactant will decrease the interfacial tension while also playing a role in the wettability alteration, which can change the unfavorable wettability of the rock to a favorable one, i.e., oil-wet to water-wet (Seng et al., 2020).

Surfactant flooding can be an effective EOR method for lower salinity reservoirs resulting in a significant reduction of the interfacial tension and alteration in the wettability (Teklu et al, 2017). Also, the decrease in clay content of the formation will lead to a decrease in the adsorption of the surfactant by the adsorbents, less absorption of the surfactant leads to more successful surfactant flooding (Amirianshoja et al, 2011 and Kar and Hascakir, 2021a)

Selecting a type of surfactant will depend on the formation properties, such as the polarity. An example of surfactant flooding being applied is in Wolfcamp on two different wells. Wolfcamp and Potiguar basins have a similar lithology in terms of clay content and its salinity (Bhandari et al, 2018). With a period of three years, the results show a significant amount of reduction in the interfacial tension and the improvement in the wettability of the rock from oil-wet to water-wet (Alvarez et al, 2018). Displayed in Figure 7 are the results of the surfactant flooding application on two different wells. From the figure, the surfactant flooding results obviously yield lower interfacial tension in comparison with waterflooding, and the Anionic 1 has the best results of achieving the minimum interfacial tension leading to a higher recovery rate.

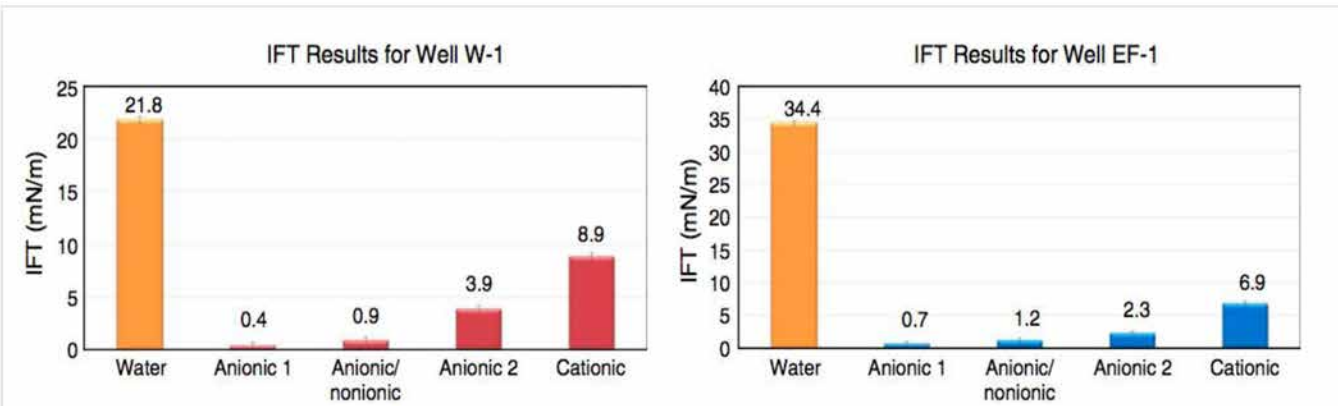

Figure 7—IFT reduction results from two different wells in the Wolfcamp basin

After the limited success of polymer flooding in the Potiguar basin, surfactant flooding can be a better option also in this reservoir with the Anionic type of surfactant injection. Using the anionic type of surfactant allows for a higher oil recovery shown by the promising results from applying surfactant flooding on Wolfcamp basin. The lowest interfacial tension found from a sample taken from the Potiguar basin is 10.98 (mN m^{-1}) (Santos da Silva et al, 2013) and the salinity of the Potiguar basin is around 500 ppm. The low clay content shown in Table 1 for the Canto do Amaro field, located in the Potiguar basin, can work in favor of the surfactant flooding, and increase its chances to succeed and improve the oil recovery (Seng and Hascakir, 2021).

Offshore: the big prize

Campos and Santos are contiguous basins that share some similar characteristics. The reservoirs were not discovered until the early 2000's and are in most cases turbidites/sandstones with heavy/intermediate (mainly) to light oils (13°-29°API). The large hydrocarbons accumulations were found in Campos basin and some of which have been flooded with water since the 2000's. The discovery of the pre-salt reservoirs moved the focus deeper reservoirs. These carbonate reservoirs are situated in depths ranging from 16,000 to 23,000 feet, below a thick layer of salt ranging from 3,300 to 6,600 feet. Although spreading under both Santos and Campos basins, it is at the former that the largest fields have been discovered so far, with wells producing up to 58,000 boe/d. The oil grade ranges from intermediate to mainly light (23°-30°API) but has a significant carbon dioxide content (from 5% up to 41%).

The Marlim and Jubarte fields were chosen as representatives of deep water, above salt fields given its oil grades and paraffin contents. Lula and Mero were chosen to discuss the opportunity of using an EOR method to dispose of CO_2.

Marlim and Jubarte: how to bring-back production to elevated levels. The Jubarte field, discovered in 2001, is a heavy oil sandstone reservoir (17 API°) located roughly 47.8 miles from the Brazilian shoreline in the northern Campos basin (Dong et al., 2019). The reservoir is 1,148 ft. thick with a water depth of 3,497 ft. (Fontanella et al., 2008). The Marlim field, discovered 16 years before is a 410 ft. thick sandstone reservoir with intermediate oil (18 to 25 API°), and a dead oil viscosity between 4 to 8 cP (Bampi & Costa, 2010; Pinto et al., 2003).

Table 3 shows the characteristics of Jubarte and Marlim fields compared at the same temperature, 20°C. At this temperature and utilizing the mobility equation given with Eq. 3, one can deduce that Jubarte oil will have a lower mobility ratio in contrast to Marlim's due to the high dead oil viscosity.

$$\lambda_i = \frac{k_i}{\mu_i} \qquad \text{Eq.3}$$

Table 3—Characteristics of Jubarte and Marlim fields in the Campos basin

Parameter	Marlim	Jubarte
Type of crude	Light – medium	Heavy
Dead oil Viscosity, cP at 20°C	400 – 500	3,000
Temperature, °C	62 – 72	76
Gravity, API°	18 - 25	17
Thickness, ft	410	1,148
Depth, ft	2,500 - 2,750	3,497
Rock type	sandstone	sandstone
Avg CO_2 (vol %)	0.12	2.04

Currently, the two fields are maintaining reservoir pressure by reinjecting produced sea water, given its availability, rather than using a low-salinity fluid that has proven to be more successful in terms of oil recovery (Jackson et al., 2106; Katende & Sagalac, 2019).

Despite having favorable water flooding conditions, there has been a steady decline in production from Marlim field as seen in Figure 8. The average production is currently around 50,000 bbl/d, with a total recovery factor of 35% of total OOIP. The build-up of wax paraffin in the risers and flowlines is due to low temperature and high pressure which contributes to the decline in production (Alvarado & Manrique, 2010). The accumulation of paraffin in the production lines reduces the inner diameter resulting in constricted tubing access and an increase in back pressure. If the paraffin is left unattended it can ultimately cause complete loss of the subsea pipeline in question (Aiyejina et al., 2011). Jubarte has avoided the accumulation of paraffin within the pipelines thanks to the pigging facilities and the implementation of thermal insulation of the flow line from the start (Colodette et al., 2007). The thermal insulation is used to keep the temperature within the pipeline three degrees Celsius higher than the wax appearance avoiding paraffin solidification within the pipeline (Colodette et al., 2008). By using the same method as Jubarte, the Marlim field would be able to solve the paraffin problem at hand.

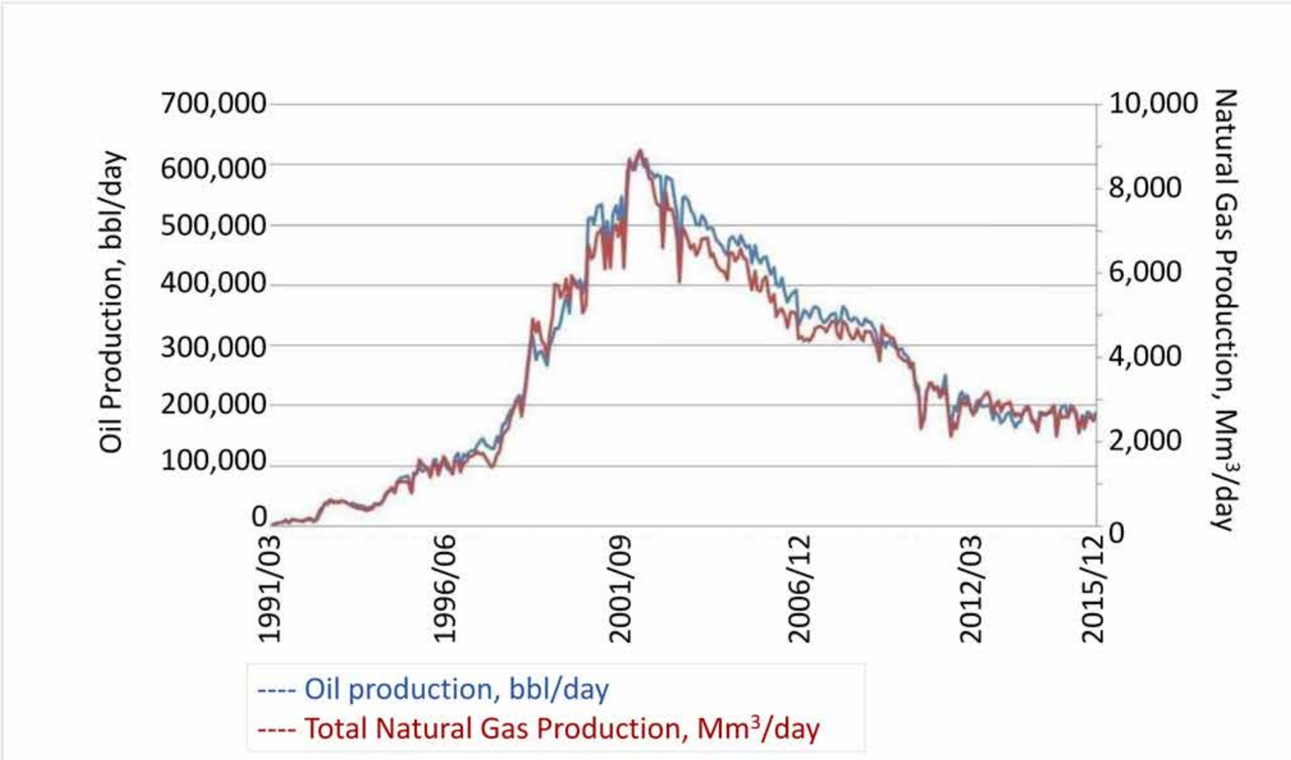

Figure 8—Historical Production - Marlim Field (ANP, 2016)

The chart in Figure 9 shows the moment when Jubarte oil production reaches its peak before it starts declining.

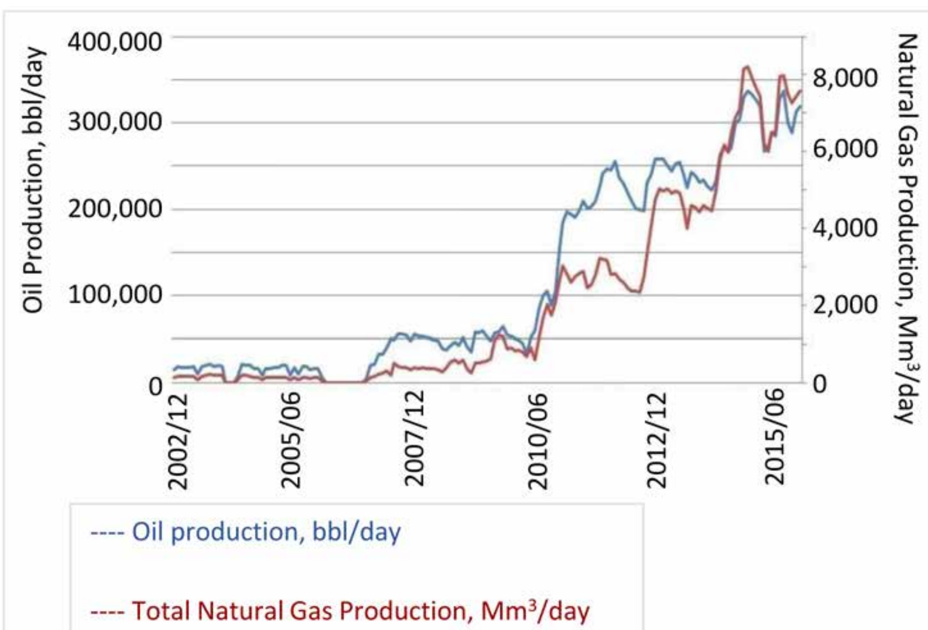

Figure 9—Historical Production - Jubarte Field (ANP, 2016)

Its oil rate has halved to an average of 156,000 bbl/d in the first five months of 2019, having recovered so far just 6% of total OOIP. Hence, both fields are strong candidates to the implementation of tertiary recovery methods. As per Table 3, the type of crude oil for Jubarte is classified as heavy oil making thermal enhanced oil recovery a seemingly good choice since the oil is heavy and the sweep efficiency needs to be improved. However, this is not the case. Thermal recovery is extremely susceptible to heat loss and it is also not an economically viable option when producing offshore (Hite & Bondor, 2005).

The next and clearer option to improve the sweep efficiency is polymer flooding. Although polymer flooding is more expensive than water flooding, it is less prone to viscous fingering while also improving the frontal stability problems that arise with the injection of water (Akbari et al., 2019). Polymer flooding can also provide an average 10-15% oil recovery after waterflooding; although, with higher levels of salinity a more concentrated polymer is needed to continue the high level of performance.

For example, two pilot projects were made in the Daqing oil field, located in the Republic of China, and the core flood experiments provided 20% oil recovery on top of waterflooding (Algharaib et al., 2014). For this reason, polymer flooding would be a good alternative to waterflooding in the Jubarte and Marlim fields.

There are three different polymers: Polyacrylamide (PAM), hydrolyzed polyacrylamide (HPAM), and Xanthan gum. The reservoir temperature of Jubarte ranges from 62 °C to 72 °C and has high salinity levels due to reinjecting produced sea water. Due to the high salinity levels, hydrolyzed polyacrylamide would not be a proper choice due to its high sensitivity to salinity. Xanthan gum or polyacrylamide would be good options for Marlim because both polymers are not affected by the sea water salinity; however, polyacrylamide begins to show instability when reaching temperatures above 62 °C at seawater salinity making this polymer not a good choice for the Jubarte field (Afolabi et al., 2019; Palaniraj & Jayaraman, 2011). Hence, the safer option is Xanthan gum for both fields.

The Santos basin and the CO_2opportunity. Table 4 shows the parameters of the Lula and Mero fields respectively with the Lula field currently utilizing the CO_2-WAG method. Mero is currently producing under an Extended Well Test regime from a single producer well and with a gas injection well (Rocha et al., 2019).

Table 4—Characteristics of Lula and Mero fields in the Santos basin (multiple sources cited in reference list)

Parameter	Lula	Mero
Type of crude	Light	Light
Dead oil Viscosity, cP	1	-
Permeability (mD)	50 - 1,000	-
Gravity, API°	31	29
Thickness, m	-	410
Rock type	carbonate	carbonate
Avg CO_2 (vol %)	8 - 18	41.88

CO_2-WAG, first implemented in Alberta Canada in 1957, is a process in which carbon dioxide is injected in the reservoir with water at alternating intervals. The main advantage of CO_2-WAG is the combination of the benefits of the two different EOR methods to improve the overall efficiency (E), that calculated as multiplication of the macroscopic (E_v) and microscopic efficiencies (E_d). In Lula reservoirs, water flooding enhances the volumetric sweep - the E_v term - while miscible flooding with CO_2(above its MMP) enhances the recovery at the pore-volume - the E_d term (Han & Gu, 2014; Afzali et al., 2018; Hascakir, 2016). The water maintains reservoir pressure and controls the mobility of $CO_2$by reducing its relative permeability. Green & Willhite (1998) further state that $CO_2$is easily miscible with crude oil in contrast to other gases at reservoir condition since it requires lower pressure to attain miscibility (Coelho, et al., 2017 and Prakosa et al. 2017). Even higher recovery efficiency can be achieved if carbon dioxide is injected in the reservoir as a supercritical fluid, due to the extraction of more hydrocarbons than carbon dioxide in the gaseous state (Jerrell et al., 2002). Since Lula field oil has high CO_2content, this method was implemented in the initial production stages to reduce CO_2 emissions due to environmental and logistical reasons. Transporting the gas to shore for processing was not feasible due regulatory and equipment constraints (Geoval et al., 2014).

When comparing Mero to Lula, it is seen that both are in the same basin and are similar types of reservoirs. However, managing carbon dioxide is a more difficult challenge for the Mero field. While CO_2content for the Mero field is averages above 40%, at Lula field it ranges between 8% and 18% (Boyd et al., 2015). Thus, making CO_2-WAG a good recommendation for the Mero field when moving into the full development phase from the pilot phase. Figure 10 shows the production from first oil until 2018. While Lula has 42 producing wells, Mero is still in its EWT phase with a single producer and a single injector, injecting all the gas/CO_2 produced. As the single well is producing 58,000 boe/d (being 53,500 of oil), a decrease in production will not be an issue now and for many years. The advantage of changing to CO_2–WAG implementation would be the avoidance of early gas/CO_2 breakthrough much like its counterpart, Lula.

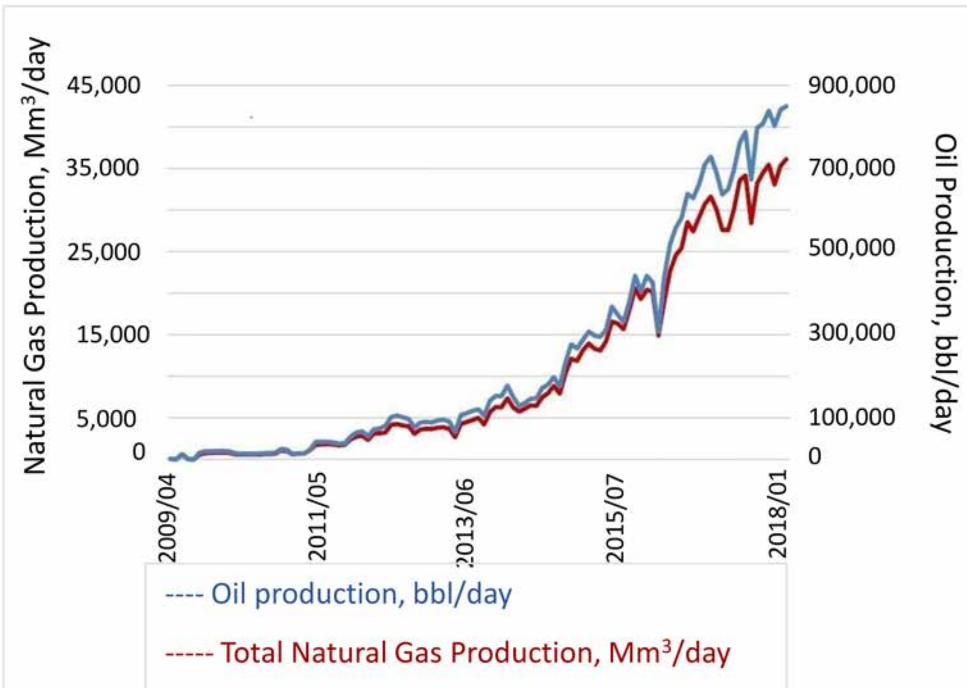

Figure 10—Historical Production – Lula Field (ANP, 2018)

Conclusion

In the beginning of the current decade, Brazil was producing almost 2 MM barrels of oil per day. Nowadays the pre-salt fields alone (that started operating 10 years ago) produce an average of 1.67 MM bbl/d. However, as the total current oil production is 2.73 MM bbl/d it means that the other basins saw a decline of more than 50% in its production levels.

The divestment by Petrobras of many assets, located both onshore and offshore, opens a window of opportunity and a need for the new owners to apply EOR methods to bring back production to higher levels and recover their investments. By reviewing the data from three onshore fields from Reconcavo, Sergipe and Potiguar and two offshore fields from Campos basin this paper has discussed issues and assessed alternatives that may similarly be applicable to other fields in the same basins.

Buracica, Carmópolis and Canto do Amaro fields presented almost none to low increase in production. One of the reasons may be credited to paraffin wax deposits. The proposal, then, is to combine to methods a thermochemical one to avoid the buildup of wax with the addition of surfactant to the injected fluid to reduce interfacial tension between water and oil and increase recovery of the latter.

Both Jubarte and Marlim have achieved success with waterflooding. They also present a continuous decline curve since reaching peak production. Polymer flooding is the solution proposed in these cases.

The pre-salt fields are still ramping up production at very high rates. Between the two alternatives in place today, CO_2–WAG seems to be the most appropriate one.

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